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February 19, 2008

Arizona Corporation Commission
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Docket Control
Arizona Corporation Commission
1200 W. Washington St.
Phoenix, AZ 85007

Re: *AEPCO's Responses to the Questions Related to Resource Planning (January 11, 2008 Workshop); Docket No. E-00000E-05-0431*

Dear Sir/Madam:

Enclosed are the original and 13 copies of AEPCO's comments and responses on the Resource Planning Issues discussed at the January 11, 2008 workshop. Its May 24, 2007 Resource Planning Responses are also attached to this filing.

Very truly yours,

GALLAGHER & KENNEDY, P.A.

By: Michael M. Grant

Michael M. Grant

MMG/plp
10421-42/1776025

Enclosures

cc (w/enclosure): Barbara Keene, Utilities Division (delivered)

Original and 13 copies filed with Docket Control this 19th day of February, 2008.

AEPCO's Comments on the Resource Planning Workshops

Docket No. E-00000E-05-0431

The Arizona Electric Power Cooperative, Inc. ("AEPCO") submits these comments and responses to the Questions Related to Resource Planning, Docket No. E-00000E-05-0431, discussed at the January 11 workshop.

In summary, the cooperatives believe that the current, but mostly suspended, Integrated Resource Planning ("IRP") Rules reporting and hearing processes should not be reinstituted. Alternatively, as described in the "Resource Planning in Western Jurisdictions" matrix, the cooperatives suggest that, as in Colorado, distribution cooperatives be exempted from the process and AEPCO be subject only to periodic reporting requirements. If, however, the Commission believes some IRP procedure is needed, a possible alternate approach would be to require the filing periodically—perhaps on a three- to four-year cycle—of information concerning utility supply-side plans, together with supporting detail as necessary. If the Commission believes some IRP procedure is needed, those individual products could then be collectively reviewed in a process and format similar to the Commission's Biennial Transmission Assessment ("BTA").

On May 24, 2007, AEPCO filed Resource Planning Responses to questions which deal with several of these and other issues. Those responses are attached.

1. *Should the resource planning process be a least cost plan or an integrated resource plan?*

   In AEPCO's case, the Rural Utilities Service ("RUS") requires an analysis showing that a resource is "least cost" before RUS-guaranteed loans are approved. However, the RUS also requires an integrated analysis of demand- and supply-side resources in arriving at a least cost plan. Further complicating the "integration" issue is the cooperatives' disaggregated nature. Thus, for example, although AEPCO takes into account in its planning the anticipated results of demand-side management ("DSM") programs, those programs are developed and delivered at the distribution cooperative level. Also, the member distribution cooperatives are responsible for certain elements of the renewables program and, in the case of Sulphur Springs Valley Electric Cooperative, it has an approved REST Plan of its own.

2. *What are the objectives/purposes of resource planning? Should the plan be approved or acknowledged by the Commission?*

   The primary objective of the resource plan is to identify preferred resources that will be needed to meet anticipated customer needs over the planning horizon in a reliable and cost-efficient manner. However, a number of other separate regulatory processes now provide those opportunities and meet those objectives in venues other than the Resource Planning Rules, which were adopted almost 20 years ago. For example, the Commission has addressed DSM programs in separate company-specific orders, as well as addressing those issues in Docket No. RE-00000C-05-0230. Similarly, the REST Rules require the annual preparation, Staff review and Commission approval of renewables programs, which contain, among other things, distributed generation, large-scale generation and power purchase component parts. Also, quite recently, the Commission, in Decision No. 70032, approved best practices and procedures for obtaining new resources for supply-side entities. Conducting yet another, separate resource planning process, given these other activities and processes, is simply unnecessary and costly.

If, however, the Commission institutes an IRP process, AEPCO recommends that it result in a prudence finding and that plans be reviewed and acted upon promptly.

3. *What utilities should be subject to the IRP Rules?*

For the reasons previously discussed, AEPCO recommends that no utilities should be required to file resource plans. Alternatively, distribution cooperatives should be exempted and AEPCO should be subject only to reporting requirements. For example, AEPCO could periodically report to the Commission its load forecasts, existing resource assessment, planning reserves and needs assessment.

4. *What resources and other information should be included in the IRP?*

The IRP process should only involve generation and not distribution or transmission planning. AEPCO's plans would likely reflect the following elements: (a) description of the cooperative, introduction and background; (b) details of the company's load forecast, which will include the expected impacts of the distribution cooperatives' DSM and distribution-level REST programs; (c) description of existing generation and purchased power resources; (d) assessment of future loads and resource balance; (e) detail of all potential supply-side resources, including distribution cooperative distributed generation renewables and any generation providers' purchased power or central station renewable resources; (f) detail of the resource expansion planning process and model(s) used, along with their engineering, operational and financial assumptions; (g) determination of AEPCO's units-only (supply-side only) resource expansion plan to establish backstop plan costs; (h) a final resource expansion plan delineating resources, their timing and costs; and (i) the impact on rates as a result of the plan.

5. *What should be the filing interval and planning/forecast horizon for IRPs?*

Again, if an IRP process is reinstituted, the cooperatives recommend a simpler, more individualized process which utilizes existing utility planning efforts and products already in place. A possible alternate approach would be to require the filing periodically—perhaps on a three- to four-year cycle—of information concerning utility supply-side plans, together with supporting detail as necessary. Those individual products could then be collectively reviewed in a process and format similar to the Commission's BTA. Although it will vary based on different factors and circumstances, AEPCO believes 20 years is generally the optimal load forecast planning horizon, with emphasis on resource plans in the first ten years.

6. *What information should be provided in compliance with R14-2-703 Reporting Requirements?*

As discussed at the January 11 workshop, the reporting requirements that were developed in the 1990s (R14-2-703.A and B) were very detailed, time consuming and costly to provide. This level of detail was necessary so that Commission Staff could independently replicate the calculations contained in individual utility IRPs. Today, such a detailed analysis is not needed and providing such information would require confidentiality agreements given the competitive generation marketplace. Current reporting requirements should be simplified and streamlined to minimize the time and expense of collecting, compiling and reporting this information. The information should be restricted to that needed to fulfill IRP objectives and reporting requirements should be consistent and applicable to all market participants.

May 24, 2007

AEPCO Comments

AEPCO's General Comments on the Resource Planning Workshops

Docket No. E-00000E-05-0431

The Arizona Electric Power Cooperative, Inc. ("AEPCO") submits these comments and responses to the Questions Related to Resource Planning, Docket No. E-00000E-05-0431, dated April 26, 2007.

In summary, AEPCO believes that the current, but mostly suspended, Integrated Resource Planning ("IRP") Rules and process should not be reinstituted. If, however, the Commission believes some IRP procedure is needed, a possible alternate approach would be to require the filing periodically—perhaps on a three- to four-year cycle—of information concerning utility supply-side plans, together with supporting detail as necessary. Those individual products could then be collectively reviewed in a process and format similar to the Commission's Biennial Transmission Assessment ("BTA").

AEPCO has an extensive, ongoing resource expansion planning process, much of which is mandated by federal regulations. This could be utilized in a periodic IRP review to avoid additional, duplicative and costly IRP requirements. Individualized filings would also accommodate the structural and service differences which exist among utilities. For example, AEPCO is not an integrated utility and serves no retail customers. Instead, AEPCO has all-requirements members who contract for all of their demand and energy from the Cooperative's resources, but as well has a partial-requirements member who has a proportionate share of AEPCO's existing resource allocations and is responsible for meeting its retail members' power and energy needs above that level. AEPCO serves the five Arizona Class A member-owners at wholesale. Each Class A member serves mostly rural customers although some urbanization is occurring around larger communities. Many of the end-use retail customers served by each Class A member are moderate- to low-income households with low customer density. This contrasts with the state's investor-owned and municipal utilities which are integrated and have much different end-use service characteristics. If a resource planning review process is needed, utility-specific filings with a collective periodic review would accommodate these and other differences among utilities, but also afford a statewide analysis.

AEPCO's Responses to Exhibit "A" Questions Related to Resource Planning

Docket No. E-00000E-05-0431

A. <u>Objectives of Resource Planning</u>

Q01 *What should be the primary objectives of a resource planning process?*

A01 The primary objective of a resource planning process should be collective periodic review of individual plans that utilize existing efforts already in place to avoid costly and duplicative analyses, reports and processes.

Q02 *Arizona first promulgated resource planning rules in 1989 (contained at A.A.C. R 14-2-701 through 14-2-704), but those rules have been suspended indefinitely by the Commission, except for those portions requiring historical reporting of data. (A) Should the Commission look at using or "tweaking" these existing resource planning rules, or are they so outdated that we should design something new? (B) Do those rules accomplish the objectives of resource planning? (C) What conditions (if any) in the industry and market have changed fundamentally since 1989 that would impact the way IRP is conducted?*

A02 As mentioned in the summary, if a statewide resource planning process is necessary, AEPCO strongly recommends a new approach that utilizes existing utility planning efforts already in place.

Significant changes in the industry have markedly impacted the control which utilities and the Commission have over the integrated process and result. When the IRP Rules were first adopted in 1989, utilities were essentially "sole source providers" for meeting the energy needs of the state. Today, for the industry and cooperatives generally, uncertainty concerning both retail and wholesale electric competition, merchant power plants, renewable resource providers, new individual renewable and distributed generation options, DSM programs and companies which focus on "nega-watts" as an alternative to supply-side planning as well as other factors have impacted considerably the premise upon which the IRP Rules were originally based. Those and other factors also apply in varying degrees to the urban and rural areas of Arizona resulting in different supply-side impacts. For example, unlike the 1990s, AEPCO now has one and will shortly have two partial-requirements members which are responsible for planning and acquiring a portion of the resources needed to meet the anticipated loads of their retail members. All of these factors have impacted significantly utilities' and AEPCO's planning processes and the control over the end result.

Q03 To what extent have traditional resource planning functions been adopted by the Commission in other proceedings and rulemakings?

A03 Since the IRP Rules were adopted, various resource planning functions which were a large part of the process in the 1990s are now dealt with in other proceedings or covered by other rules. For example, the Commission has in place the EPS Rules and has proposed the REST Rules dealing with renewable requirements which have both distribution- and generation-level components. Competitive procurement was the subject of the Track B proceeding, has also been required in individual rate case proceedings and additional comments on it are also being solicited separately as part of this docket. Distribution-level DSM programs are also being addressed in individual filings and/or rulemaking proceedings. Obviously, these elements are still factors in the supply-side planning process, but the fact that they are being addressed in other ways makes much less "integrated" the IRP assumption on which the original rules were based and the process was structured.

Q04 *Are some traditional IRP processes best left to regional organizations rather than the state?*

A04 No. However, requirements imposed by regional organizations, such as the NERC, as the new FERC ERO, and WECC in its supporting role, should be taken into account in the planning process.

Q05 *What role should the regional planning processes, particularly regional transmission organizations, play in the process?*

A05 Again, to the extent that such processes impose requirements on the utility, these requirements should be considered within the resource expansion planning process. AEPCO supports the general concept that transmission planning for regional grid reliability should occur as a completely separate process from resource planning, while transmission planning associated with connecting to and delivering power from particular resource options will be part of the resource planning process.

Q06 *To what extent, if any, should a Commission decision "accepting" or "approving" a plan (or a part of a plan) be regarded as a finding of "prudence" in subsequent rate cases?*

A06 If the Commission approves a resource plan, or a portion thereof, all or part of the resources identified in that plan should be deemed prudent for rate recovery in a subsequent rate case.

Q07 *What types of information should be included in resource plans? Should this information be organized in a specified manner so that plans from each utility are consistent with each other, containing the same type of information, and in the same part of the filing?*

A07 Again, if an IRP process is reinstituted, AEPCO recommends a simpler, more individualized process which utilizes existing utility planning efforts and products already in place. Resource plans would present the results of each individual utility's planning effort.

The individual utility plans would likely contain the following elements: (a) description of the utility, introduction and background; (b) details of the company's load forecast which will include, in AEPCO's case, expected impacts of the distribution cooperatives' DSM programs; (c) description of existing generation and purchased power resources; (d) assessment of future loads and resource balance; (e) detail of all potential supply-side resources, including distribution cooperative distributed generation and any AEPCO purchased power or central station renewable resources, along with their engineering, operational and financial assumptions; (f) detail of the company's resource expansion planning process and model(s) used; (g) determination of the company's units only (supply-side only) resource expansion plan to establish backstop plan costs; (h) a final resource expansion plan delineating resources, their timing and costs; and (i) the impact on rates as a result of the plan.

B. Resource Planning Processes

Q01 *Which utilities should be required to file resource plans? (a) Electric—(1) All, (2) Utilities over a certain size (based on megawatt load or annual sales), (3) Those with generating units, (4) Other; (b) Natural Gas—(1) All, (2) Utilities over a certain size (based on therms sold or annual sales), (3) None, (4) Other.*

A01 For the reasons previously discussed, AEPCO recommends that no utilities should be required to file resource plans. Alternatively, given, among other things, AEPCO's generation-only role and the fact that much of its forecasting, resource planning and RFP/procurement processes are federally mandated, cooperatives should be excluded from filing resource plans.

Q02 *Should resource planning consider transmission as well as generation resources?*

A02 No. IRP should not consider transmission resources as an alternative to generation resources. Although seeking transmission resource alternatives as a cost effective solution/augmentation to planned resource expansion implementation is both prudent and necessary, transmission and resource planning should otherwise continue as wholly separate functions and not be part of a common IRP process.

Q03 *What should the planning horizon be for a resource plan (i.e., 10 years, 15 years, 20 years or longer)?*

A03 AEPCO recommends that 20 years is the optimal short-term planning horizon. AEPCO currently utilizes New Energy Associate's STRATEGIST planning model in its resource expansion planning, modeling and analyses. STRATEGIST divides the future into two distinct time periods—the Planning Period, which begins in the current year and extends twenty years, and the Study Period, which begins in the current year and extends for as many years as necessary such that the total present value costs of each plan brought back and added to the base year has no further effect on the cost stream. AEPCO selects as its preferred plan the combination of the lowest total present value cost Planning Period and Study Period ranks.

Q04 *How frequently should a utility be required to file a resource plan (i.e., every two, three or four years)?*

A04 If a formal resource planning process is reinstituted, AEPCO recommends a three- to four-year filing cycle.

Q05 *Should there be a "Biennial Resource Assessment" similar to the requirement for a Biennial Transmission Assessment contained in Arizona Revised Statutes § 40-360.02 (g)?*

A05 As explained previously, AEPCO believes that this BTA process could be used to jointly consider the individual planning products of each utility, although on a three- to four-year cycle.

Q06 Should resource plans be filed simultaneously by the utilities as in the past (so the Commission could focus on statewide issues), or should they be individually filed in alternating years or periods (in which the Commission could focus on the specific issues for each utility)?

A06 There are advantages to each approach. However, AEPCO favors the three- to four-year simultaneous filing with a collective review similar to the BTA process if the IRP process is reinstituted.

Q07 What time limits, if any, should apply to the Commission's processing of a resource plan?

A07 Because of rapid growth and the frequency of annual load forecast updates and updated internal resource plans, if a Commission review is reinstituted, the review should be completed within a year.

Q08 Should there be public hearings on resource plans? Should the rules allow for intervenors? Should parties be allowed to call and cross-examine witnesses?

A08 Consistent with the BTA process, AEPCO suggests a workshop(s) and a public participation process rather than the more formal hearing, testimony filing and intervention procedure.

Q09 How can a resource planning process be developed which takes into account changes that occur between filings? How can flexibility to adapt to new, unanticipated situations be maximized? Should the utility file annual updates of its resource plan? Should the utility file amendments to its plan as major decisions or changes are made?

A09 These concerns could be addressed by the filing of an IRP plan one year followed by an annual update, if necessary, until the three- to four-year cycle would commence again. The possible annual report would contain load forecast variations or changes in other key assumptions if they have affected resource expansion.

Q10 Should resource plans include a short-term "action plan" (such as the time between filing of resource plans) in which utilities could obtain more direct Commission direction and/or approval for certain critical items that must be decided in the short term?

A10 AEPCO believes that individual filings can address such circumstances if and when they arise.

Q11 How is the resource planning process affected by a building moratorium?

A11 Obviously, if a moratorium is imposed on a certain type of resource or supply-side alternative that has been selected as part of a resource plan, delaying or deferring that alternative could impact the cost effectiveness of the utility's resource implementation strategy.

Q12 To what extent should the process be public? How much data can be discussed and/or debated publicly given competitive considerations that are now a part of the wholesale marketplace?

A12 As discussed in response to Q08, public participation could be accommodated through a workshop process. It is likely, however, that certain data will need to be protected as confidential.

Q13 Should standardized RFP/Solicitation procedures be adopted as part of the process?

A13 AEPCO is already subject to federally-required RFP and solicitation procedures which must be followed to obtain loan funds and maintain mortgage compliance.

AEPCO's primary loan guarantor is the Rural Utilities Service ("RUS"), via the lender, the Federal Financing Bank ("FFB"). The FFB through RUS makes loans for new resources under the Rural Electrification Act of 1936.

RUS approval is required for all loans in relation to new resource additions and existing resource modifications. The Code of Federal Regulations (generally, 7 C.F.R. § 1710, *et seq.*) requires that each borrower must provide, and RUS must approve, an annual load forecast, a construction work plan, a long-range financial forecast—which includes the new resource(s), DSM or renewables facilities for which loan funds are being requested—a Power Cost Study and, where applicable, a Borrower's Environmental Report. Comprehensive project-specific engineering and cost studies to support financing requests and construction of additional generating capacity, including existing capacity replacement, must be produced. These studies include detailed economic present value analyses of the costs and revenues of available self-generation, load management, energy conservation and purchased power options, including the financial viability of the purchased power supplier(s), assessments of service reliability and financing requirements and risks. These studies must also consider alternative unit types and sizes, fuel alternatives, system stability, impacts on the interconnected transmission system and system dispatch.

AEPCO is also required to solicit proposals from all reasonable potential sources of power such as other Cooperatives, investor-owned utilities, municipal utility organizations, federal and state power authorities, independent power producers and co-generators. These solicitations for proposals are required to be published in at least three national publications in addition to direct contact. The applicant is also required to inform RUS of progress in the solicitation as negotiations progress. Final plans must include sufficient detail to show that the present value analyses of alternatives and their effects on total power costs over the forecast period result in the most economical, strategic and effective means of meeting AEPCO's planned resource expansion capacity.

C. <u>Need Determination (Load Forecasting)</u>

Q01 *How are load forecasts to be conducted? Should there be one consistent methodology used by all utilities, or should each utility have the flexibility to use the methodology that it prefers? Should the Commission specify the methodology by which forecasts are developed?*

A01 For AEPCO, load forecast requirements are also specified by federal regulations. Each three-year load forecast work plan and annual Class A member load forecast is required by RUS to be developed from the bottom up in coordination with each Class A member. That distribution cooperative product is reviewed and approved by the cooperative's Board of Directors and subsequently by RUS. It is then used in financial planning, operations and to support future loan applications. Each member's forecast is based on solid econometrics, weather data, historical data, growth expectations, the probability of new loads and prior experience. AEPCO's load forecast is a roll-up of the six Class A member individual load forecasts and is reviewed and approved by its Board of Directors and subsequently by RUS.

Q02 *What time period should load forecasts reference?*

A02 AEPCO's load forecasts produced annually in coordination with its Class A distribution cooperatives cover the time period from the current year to 20 or more years into the future. This is consistent with the resource planning horizon recommended in response to Q03 in the "Resource Planning Processes" section.

Q03 *How can the Commission (or should the Commission) review load forecasts when considering a resource plan?*

A03 Load forecasts, developed as described previously, which are used in relation to the resource plan could be made available for Commission review.

Q04 *What is an acceptable margin of error in viewing actual, experienced, historic peaks compared with forecasted peaks? Should a significant, unexplained deviation between the historic and forecasted peak trigger an amendment or update of the resource plan?*

A04 AEPCO generally accepts an annual forecast error in the range of five percent (5%). Normally, actual peaks fall well within this margin. A significant, unexplained deviation should only trigger an amendment or update if the cause is not temporary, such as an unusual, extreme weather result.

D. Demand Reduction (Demand-Side Management)

Q01 *What role should DSM play in the resource planning process?*

A01 Because of the disaggregated nature of AEPCO and its member distribution cooperatives, DSM programs will be developed and delivered at the distribution cooperative level. That subject is being dealt with separately in Docket No. RE-00000C-05-0230. However, as explained previously, anticipated results of distribution level DSM programs are taken into account in formulating AEPCO's resource plan.

Q02 *Should existing Commission activities in DSM be brought within the realm of the resource planning proceedings?*

A02 No.

Q03 *How is resource planning affected by existing DSM programs and DSM proceedings presently pending before the Commission?*

A03 AEPCO uses the distribution cooperative's load forecasts which include the effects of distribution level DSM programs in formulating its resource plan.

Q04 Should the Commission adopt the following PURPA standards included in the Energy Policy Act of 2005: (1) Net metering? (2) Smart metering?

A04 AEPCO does not believe that net metering should be adopted because, among other considerations, it does not take into account the issues of capacity as well as the costs of infrastructure to deliver utility power or receive renewable power. Smart meters should be addressed on a case-by-case basis. In general, however, smart meters combined with properly designed rates are a good concept.

E. Filling Need Requirements (Supply-Side Planning)

Q01 What are the supply-side resource requirements that must be planned and filled in the future and how do we decide what those requirements are?

A01 AEPCO uses a periodically updated loads and resources table which includes its latest load forecast, current portfolio of resource options and imposes three separate reserve margin criteria to determine its future resource excesses and shortfalls by month for the next 20 years.

AEPCO's first reserve criterion is to impose a 12% minimum reserve margin. AEPCO's second reserve criterion is to ensure that its share of the Southwest Reserve Sharing Group's ("SRSG") single largest hazard is set aside and ready to use on a one-hour emergency basis. The third reserve criterion was adopted by AEPCO's Board of Directors as a hedge against hotter than expected or normal weather. The delta between the Class A member medium economic and high weather forecasts is added to the other two criteria.

On average, this trio of reserve requirements, when calculating AEPCO's loads and resources situation, results in reserve margin percentages in the 14-18% range, growing towards the high end of the range over time as the high weather forecast increases. AEPCO uses the loads and resources results as the backdrop for deciding how much capacity is required. The STRATEGIST model decides the size, timing and cost of resources that best meet this capacity need. Risk management analyses, assumption sensitivities and qualitative considerations then are applied to select the best of the least cost plans.

Q02 *What portfolio(s) of options are best for filling increased load demands?*

A02 AEPCO's resource planning process determines what options are best, including the effects of renewable distributed generation and DSM programs at the distribution cooperative level.

Q03 *How should risk management be factored into the decision making process?*

A03 AEPCO conducts a wide range of modeling sensitivity analyses in its standard resource planning modeling and expansion studies to minimize risk associated with its final resource expansion plan.

Q04 *How should fuel diversity be evaluated?*

A04 Please <u>see</u> the response to Q09 below. AEPCO considers all types of resources utilizing all types of fuel in its evaluation of potential demand and supply-side alternatives. AEPCO does not recommend favoring or penalizing any particular fuel in analyzing potential resource expansion alternatives.

Q05 *Can an expanded use of utility-scale solar electric generation be integrated with existing coal-fired operations?*

A05 Yes.

Q06 *How could supply-side planning be affected by the new Renewable Portfolio standards adopted by the Commission for Arizona?*

A06 Capacity required and forecast for installation under AEPCO's Commission-approved plan to meet Renewable Portfolio Standard requirements, including distributed generation efforts at the distribution cooperative level and larger scale or renewable purchased power agreements at the AEPCO level, will be taken into account in its resource plan.

Q07 *What is the risk of future carbon taxes or penalties on existing and future fossil fuel generation options? How can this risk be evaluated and quantified?*

A07 Like other risk and sensitivity criteria such as high natural gas costs, SO_2 compliance costs, unexpected load growth and extreme weather conditions, the risk of future carbon taxes should be a key sensitivity input. These can be evaluated most simply as cost additions to the capital cost of any new fossil fuel-based resource.

Q08 *Should one computer production cost modeling program be utilized?*

A08 No. Mandating only one program could require substantial extra investment in software, hardware, infrastructure and labor dollars for those companies who do not have or use the mandated model.

Q09 *How should non-utility generation (i.e., merchant generation, distributed generation) be considered in resource plans?*

A09 AEPCO sees a resource plan as a blueprint, or map, for future resource expansion. What resources ultimately supply the capacity identified in a resource plan will be determined in the RFP and solicitation phase. Non-utility generation (i.e., merchant generation, independent power producers and/or distributed generation) is considered in this phase via the solicitation for resource capacity which is required by RUS and federal regulations.